Ministry of Energy and Minerals
The United Republic of Tanzania

The Project for Review of the Natural Gas Utilization Master Plan in Tanzania

Final Report
(Disclosure Version)

August 2016

JAPAN INTERNATIONAL COOPERATION AGENCY
(JICA)

THE INSTITUTE OF ENERGY ECONOMICS, JAPAN
(IEEJ)

Ministry of Energy and Minerals
The United Republic of Tanzania

The Project for Review of the Natural Gas Utilization Master Plan in Tanzania

Final Report

(Disclosure Version)

August 2016

JAPAN INTERNATIONAL COOPERATION AGENCY
(JICA)

THE INSTITUTE OF ENERGY ECONOMICS, JAPAN
(IEEJ)

Contents

Figure

Table

Abbreviations

Acronym	Definition
Bbl	Barrels
Bcf	Billion cubic feet
Bn	Billion
Bpd	Barrels per day
BOE	Barrels of Oil Equivalent
BTU	British Thermal Units
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CGT	Capital Gains Tax
CNG	Compressed Natural Gas, used for vehicles or transport of natural gas
CPF	Central Processing Facility
DFI	Development Finance Institution
DGS	Domestic Gas Sales
DSM	Dar es Salaam
ECIC	Export Credit Insurance Corporation
E&P	Exploration & Production
EOI	Expression of Interest
EPC	Engineering, Procurement and Construction
EPP	Emergency Power Producer
ESIA	Environmental and Social Impact Assessment
ESMP	Environmental and Social Management Plan
EUR	Euros
EWURA	Energy and Water Utility Authority
FC	Financial Close
FEED	Front End Engineering and Design
FID	Final Investment Decision
First Gas	Start of production of natural gas
FLNG	Floating LNG
GDP	Gross Domestic Product
GFC	Global Financial Crisis
GIIP	Gas Initially in Place
GMP	Tanzania's Draft Gas Utilization Master Plan

GoT	Government of Tanzania
Greenfield	Development of a project in an area where no projects exist
GSA	Gas Supply Agreement
GTF	Gas to Fertilizer
GTI	Gas to Industry
GTL	Gas to Liquid
GTM	Gas to Methanol
GTP	Gas to Power
GTPET	Gas to Petrochemicals
GWh	Giga Watt hours
GX	Generation Capacity
HH	Henry Hub
IDC	Interest During Construction
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
IMF	International Monetary Fund
IOC	International Oil Company
IPP	Independent Power Producer
IRR	Internal Rate of Return
JCC	Japan Crude Cocktail
JICA	Japan International Cooperation Agency
Ktpa	Thousand tonnes per year
Landed Cost	Cost of bringing gas onshore for further use, inclusive of a return on investment for the gas field developer
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MEM	Ministry of Energy and Minerals
MM	Million
MMBTU	Million British Thermal Units
MMBOE	Million Barrels of Oil Equivalent
MMSCF	Million Standard Cubic Feet
Mn	Million
MTG	Methanol to Gasoline
MTI	Ministry of Trade and Industry
MTO	Methanol to Olefins
Mtpa	Million tonnes per year

MTPA	Million tonnes per Annum
MWh	Mega Watt Hours
NGO	Non-Governmental Organization
NGV	Natural Gas Vehicles
NOC	National Oil Company
NPK	Nitrogen, Phosphorus and Potassium
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
ODA	Official Development Assistance
O&G	Oil and Gas
O&M	Operations & Maintenance
OPEC	Organization of the Petroleum Exporting Countries
POD	Plan of Development
PPA	Power Purchase Agreement
PPP	Private Public Partnership
PPT	Petroleum Production Tax
Proven Reserves	Quantity of energy sources estimated with reasonable certainty, form the analysis of geologic and engineering data, to be recoverable from well-established or known reservoirs with the existing equipment and under the existing operating conditions. Also called Proved Reserves, Measured Reserves and 1P Reserves
PSA	Production Sharing Agreement
REA	Rural Energy Agency
ROE	Return on Equity
Rovuma Basin	Offshore basin at mouth of the Rovuma River
SAM	Social Accounting Matrix
Single Buyer	Purchaser of DGS for on-sale/distribution among downstream projects within Tanzania
SME	Small and Medium Enterprises
SOE	State Owned Enterprise/Entity
SPA	Sale & Purchase Agreement
SPV	Special Purpose Vehicle
SSA	Sub-Saharan Africa
STEM	Science, Technology, Engineering and Mathematics
SWF	Sovereign Wealth Fund
TANESCO	Tanzania Electric Supply Company Ltd.

Tanzania Inc.	Government of Tanzania and TPDC (considered together)
T&T	Trinidad and Tobago
TCA	Technical Co-operation Agreement
Tcf	Trillion cubic feet
TDV	Tanzania Development Vision 2025
TPDC	Tanzania Petroleum Development Corporation
Tzs	Tanzanian Shillings
USC	Ultra-super Critical (Coal thermal plant)
USD	United States Dollars
US EIA	United States Energy Information Administration

Chapter 1 Introduction

Chapter 1 Introduction

1.1 Background of the Study

In the east African region, no significant activities have been observed with respect to fossil energy development until recently. The situation is the same in Tanzania, where small amounts of coal and natural gas, 100,000 tonnes and 33 billion cubic feet (Bcf) or 820,000 tonnes oil equivalent (toe), respectively, are produced locally and used mostly for power generation. After the Tiper Refinery in Dar es Salaam with a small capacity of 18,000 bpd was shut down in 1999, the supply of petroleum products has been solely depended on imports.

However, in recent years, as new discoveries of large-scale gas fields have been made in deepwater blocks, the Government of Tanzania is actively seeking to develop these resources. Natural gas development in Tanzania started in 1974, when the Songo Songo gas field located 200 km south of Dar es Salaam was discovered across an area extending from shore side to shallow offshore of the Songo Songo Island. In 2001, the World Bank decided to support the development of the Songo Songo gas field and related gas utilization facilities. In 2004, the gas field and the gas system were completed to start supplying fuel for power generation and industrial use in the Dar es Salaam district. In addition, to significantly increase the gas supply for domestic requirement, a 534 Km pipeline with the capacity of 784 Bcf per year was constructed connecting the Mnazi Bay gas field located in a shallow water block further south to Dar as Salaam, upon completion of which a newly constructed Kinyerezi I Thermal Power Station commenced operations in the summer of 2015. Further, as mentioned above, presence of deepwater gas fields had been confirmed with an estimated reserve of 47.13 trillion cubic feet (Tcf), on the basis of gas initial in place according to the estimates made by the Tanzania Petroleum Development Corporation (TPDC) at the end of December 2015. Since the above reserve size is far larger than that of the existing gas fields onshore and shallow offshore (10.12 Tcf, same basis as above), high expectations are held on commercial development of an LNG project in Tanzania just like in Mozambique.

The newly discovered gas fields have an immensely large scale in comparison with the existing shallow water fields. However, since they are located in very deep waters, many difficult tasks have to be sorted out to clear high technical and economic hurdles before their development work is carried forward. It is estimated that development costs of gas fields could amount to as much as 20 to 50 billion US dollars. Securing the revenue justifying an initial investment of such magnitude requires an LNG project that can provide a substantial volume of anchor demand derived from the world markets, and its feasibility becomes the key to deciding the development of a deepwater gas field. Since any of the local consumption elements including gas-based industries such as fertilizer, power generation, and other industrial, commercial or residential fuel use, is too small in their demand scale as explained in Chapter 4 and, as observed in the past, in developing countries with immature domestic market, commercial development of large gas fields was difficult to achieve by basing the projects on such demands. If a prospect has been established one way or the other that a large gas field located in deep waters can be developed, then it becomes possible to address various measures of demand development including large-scale gas-fired power plants. Still, to bring such a project to a reality, it will be necessary to: (a) ensure proper gas prices and sufficient take-off amount to enable the gas field development and pipeline construction, (b) ensure adequate supply of funds, technology, human resources as a support for the foregoing, and (c) press forward systematic improvement of infrastructure such as power plants, transmission and distribution networks, gas industry, and so on. It is also necessary to prepare proper laws, regulations and institutions to support implementation of these works.

Under such circumstances, the Government of Tanzania is developing the Natural Gas Utilization Master Plan (NGUMP) as a guide for effective utilization of natural gas resources with the support of the Government of Trinidad and Tobago. However, the NGUMP (Draft-2) is not sufficient in providing information on international LNG market trends, discussion of the design for upstream sector development with commercial viability, and projection of the domestic demand in Tanzania, and also fails to indicate a concrete development roadmap. In order to examine the strategy for assistance in the energy sector including the future power systems, an in-depth study is required in the areas such as the development design for deepwater gas fields, feasibility of an LNG project, and a detailed overall development plan including a projection on domestic natural gas demand in Tanzania.

Against the above background, the Government of Tanzania has requested that the Japanese assistance be given for its review of the NGUMP and also in formulating a natural gas development and utilization plan with feasibility substantiated by necessary economic evaluations, and JICA has decided to undertake the project.

1.2 Objectives of the Study

In order to examine the strategy for assistance to be given to Tanzania's gas sector in the future, the following activities will be carried out taking into consideration the results of a review on the current NGUMP (Draft-2).

Examine economics in development of respective gas field, feasibility for each of various types of natural gas usage, and economics of specific utilization plans;

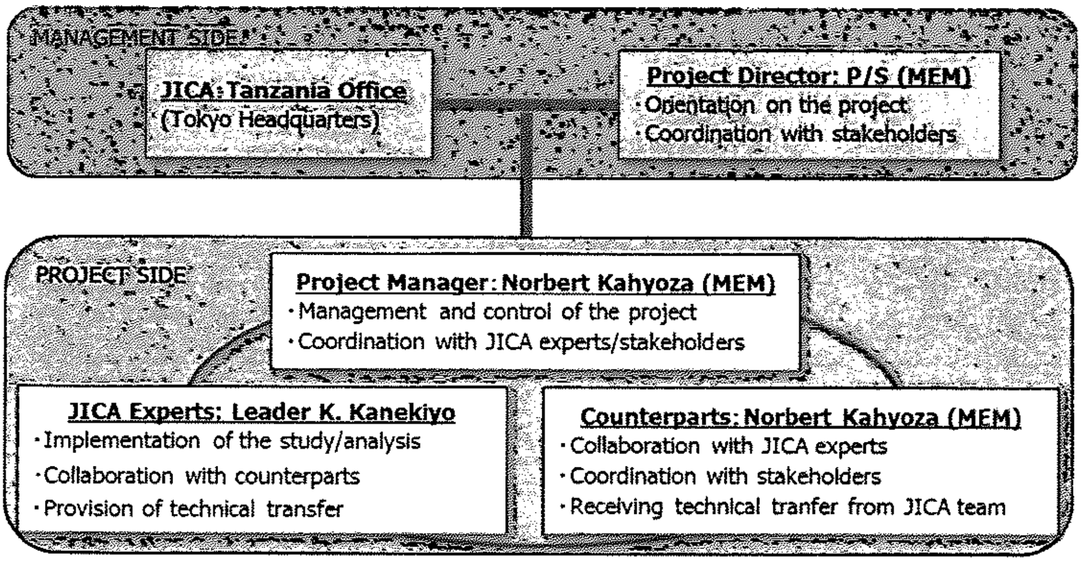
Based on the above examination on respective areas, propose a plan and a roadmap for developing a robust natural gas utilization industry that can deal with various risks involved in development of deepwater gas fields, while assessing the impact of development of gas related fields on economic growth as well as poverty reduction;

Identify the human resource development needs in gas related infrastructure development and other fields related to gas;

In carrying out this Study, a special emphasis will be placed on collaboration between the JICA study team and the Tanzanian counterparts (hereinafter may be referred to as the C/P), as well as three Visit Japan Programs by invitation to be organized for better understanding of the matters in general by the Tanzanian counterparts.

1.3 Study Organization, Team and Function

1) This Study was carried out by the organization as shown below:



P/S: Permanent Secretary

Figure 1.3-1 Study organization, team and their function

2) The JICA team participating in this Study comprises 18 experts as tabled below:

Table 1.3-1 Study Team Members

Category	Name	Affiliation
Team Leader/Overall Plan	Kensuke Kanekiyo	The Institute of Energy Economics, Japan (IEEJ)
Secretary/Overall Plan/Economic and Financial Analysis	Shinji Omoteyama	
Overall Plan/ LNG Market/Demand Forecast	Yoshiaki Shibata	
Upstream: Gas Field Development & Production	Satoshi Nakanishi	
International Gas/LNG Outlook & Gas Demand Analysis	Tetsuo Morikawa	
Organization/Institution/Human Resources	Koji Horinuki	
Gas Distribution/Marketing Business	Hiroyuki Motohashi	Tokyo Gas
International Gas/LNG Outlook & Gas Demand Analysis	Hiroshi Hashimoto	Tokyo Gas
LNG Plant (1)	Kotaro Nitta	JGC Corporation
LNG Plant (2)	Noriyoshi Nozawa	Chiyoda Corporatin
LNG Plant (3)	Ko Hosokawa	Chiyoda Corporatin
Fertilizer/Annmonia Plant	Yasuhiko Kojima	Toyo Engineering
Gas Plant (1) : Methanol	Manabu Onoda	Toyo Engineering
Gas Plant (2) : GTL	Norihiro Takama	Chiyoda Corporatin
Gas Plant (3): DME	Mitsuo Morita	JGC Corporation
Gas-thermal Generation Plan	Kyoji Fujii	Yachiyo Engineering
Gas for Transport (CNG)	Takeharu Koba	Yachiyo Engineering
Environmental and Social Considerations	Norio Shigetomi	MRI

3) The Tanzanian counterparts were assigned by relevant organizations such as MEM, TPDC, etc. Key persons of the counterparts as below;

Table 1.3-2 Counterpart Members by Groups

Group		Sub-Group		JICA Team (Head)	Tanzania Counterpart	
					Institution/position	Names
1	Planning & Coordination	1.1	Overall Plan and Roadmap	K. Kanekiyo	MEM - Assistant Commissioner (TPDC -Director for Downstream)	Norbert Kahyoza (Head of NGUMP) (Wellington Hudson)
		1.2	Economic and Financial Analysis	S. Omoteyama	MEM -Senior Economist TPDC-Senior Planning Officer	Oscar Kashaigiri Lwaga Kibona
		1.3	Organization/Human Resource	K. Horinuki	MEM-Gas, Energy Engineer	Seleman H. Chombo
		1.4	LNG/Natural Gas Market/Price Outlook	T. Morikawa	MEM-Gas, Energy Engineer	Seleman H. Chombo
		1.5	Environmental and Social Considerations	N. Shigetomi	MEM - Environmental Officer	Theodore Silinge
		1.6	Administration & Editing	S. Omoteyama	MEM-Gas, Energy Engineer	Seleman H. Chombo
2	Upstream		Gas field development & production	S. Nakanishi	TPDC-Manager Gas Business	Emmanuel Gilbert
3	Demand (Fuel use)	3.1	Demand Forecasting	Y. Shibata	POPC-Economist	Omary Athuman
		3.2	Gas-thermal Generation Plan	K. Fujii	TANESCO	Patrice Tsakhara
		3.3	Municipal Gas Supply and Market	H. Motohashi	TPDC-Planning Officer	Kant Baraka
		3.4	Gas for Transport (CNG)	T. Koba		
4	Gas Plant		JGC (LNG, DME, etc)	K. Nitta	MEM- Geologist	Mussa Abbasi
			Chiyoda (LNG, GTL, etc)	N. Takama	Viwanda	Carolyn Limo (Industry)
			Toyo (Fertilizer, Annmonia, etc)	Y. Kojima	Viwanda	Kamara Gombe (Industry)

1.4 Basic Framework of the Study

This Study aims to provide the Gas Utilization Master Plan that benefits the entire Tanzanian society compliant to the existing policies, in particular the Natural Gas Policy 2013and the National Energy Policy 2015. The Study was conducted under the following framework.

1.4.1 Scope of Study

Natural gas resources discovered in Tanzania are classified into two types with significantly different features; those located in the shallow water, such as Songo Songo and Mnazi Bay, and those located in the deepwater of Block-1, 2 and 4. Shallow water gas fields are already developed and producing, and will be expanded easily applying conventional methods. But their reserves are relatively limited. On the other hand, while deepwater gas reserves are huge, they are located in really deepwater of 1,100m - 2,500m, and modern sophisticated technologies must be mobilized to develop them. This will in turn requires huge capital investments and significant time.

In order to thoroughly consider the different features of gas field development, this Study considered the future gas development plan for a super long period up to 2045 and in three phases as below:

Phase-1: 2015-2025...Production from the existing shallow water gas fields will be expanded as domestic demand grows, while development of deepwater gas fields will be implemented.

Phase-2: 2025-2035...Production from deepwater gas fields and LNG export start. Domestic gas use as fuel as well as feedstock for gas industries will gradually increase.

Phase-3: 2035-2045...Deepwater gas will be fully utilized for domestic use as well as export.

In order to pursue gas utilization in most beneficial manner and to strike a reasonable balance between domestic use and export, this study will consider plausible gas utilization options thoroughly as below;

Domestic fuel use...power generation, industry, transport and residential and commercial markets

Domestic use as feedstock...Fertilizer/Ammonia, Methanol/Petrochemicals, Gas to Liquid (GTL), Di-methyl Ether (DME), Methanol to Gasoline (MTG). Some portion of these products may be exported

Export...LNG

In addition, capacity building will be considered in two different manners.

Capacity building of counterparts to brush up capacity to formulate and review master plan.

Capacity building strategy to foster work force necessary for gas industry development.

1.4.2 Study flow

This Study was conducted in three phases as shown in Figure 1.4-1.

In the first approach, natural gas demand in Tanzania is compiled citing the ongoing another JICA/MEM study "The Project for Formulation of Power System Master Plan in Dar es Salaam and Review of Power System Master Plan 2012 (hereinafter referred to as "PSMP Study")". Natural gas demand for fuel use and power generation is cited from the preliminary outcome of the PSMP Study. In addition, gas for feedstock is assessed assuming standard gas project models. These outcomes are explained in Chapter 4 and 8.

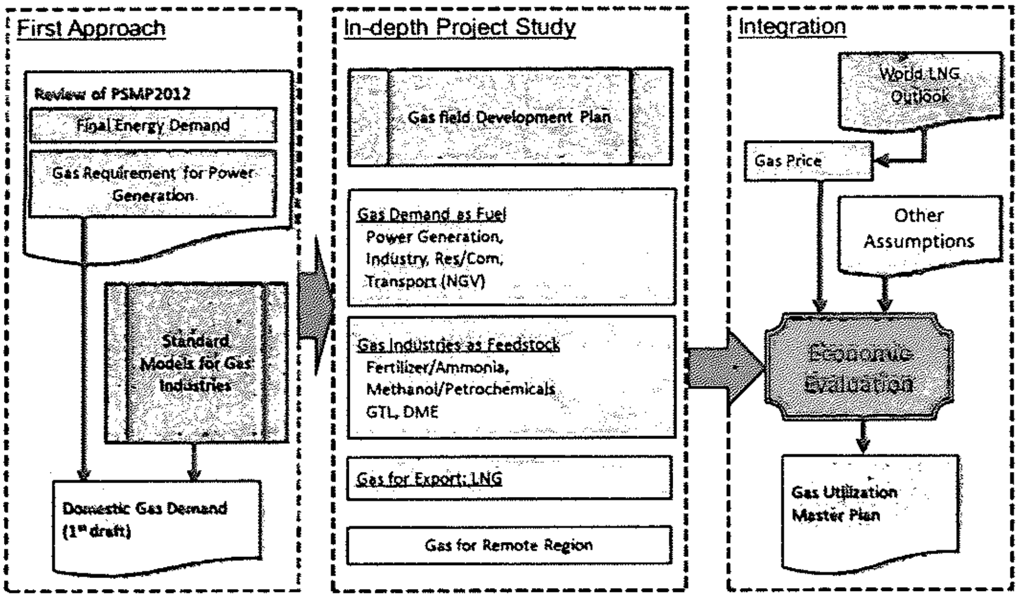


Figure 1.4-1 Study Flow

In the next stage, in-depth study was conducted to evaluate benefits of various gas utilization projects as follows:

Upstream gas field development and its economic model

Gas demand as fuel for power generation and transport, industry, residential/commercial use. These will be the requirement for the upstream gas production.

Economic model of gas utilization projects such as LNG, fertilizer/ammonia, methanol, GTL, DME and MTG.

Gas transportation model study for areas remote from the natural gas pipeline.

In the integration stage, the above studies on individual gas projects will be comparatively analyzed and formulated into a comprehensive master plan. A roadmap to implement this master plan will also be formulated to show development pathway and important milestones.

1.4.3 Contents of Study

Major contents of the above study were conducted as follows:

1) Identification of the natural gas market/demand
Power production to be cited from the PSMP Study
Feedstock for gas industries (fertilizer, methanol, GTL, DME)
Fuel demand (industry, res/com, transport=CNG) to be basically cited from the PSMP study and with additional investigations
World LNG market outlook, demand, and price trends.

2) Development plan and cost estimation
Upstream development, in particular deepwater gas fields
Downstream (gas industries and gas utilization projects)
=> LNG, Fertilizer/ammonia, GTL, DME, CNG, MTG, other use
Gas delivery for distant markets

3) Economic Evaluation
Construction of analytical models
Evaluation of individual economics for standard model projects and price scenarios.
Prioritization and aggregation

4) Draft Gas Development/Utilization Plan
Synchronized development of upstream and downstream
Roadmap with coherent time schedule
Required workforce for LNG projects and challenges for human resource development

1.4.4 Method of Project Evaluation

Economic and financial evaluation of individual projects was conducted in three phases as illustrated in Figure 1.4-2. Starting with formulation of project plans, project cash flow tables were created for final economic and financial analysis. While outlines of these analyses are explained in this report, please refer to each model for detail assumptions, model structures and calculation outcomes.

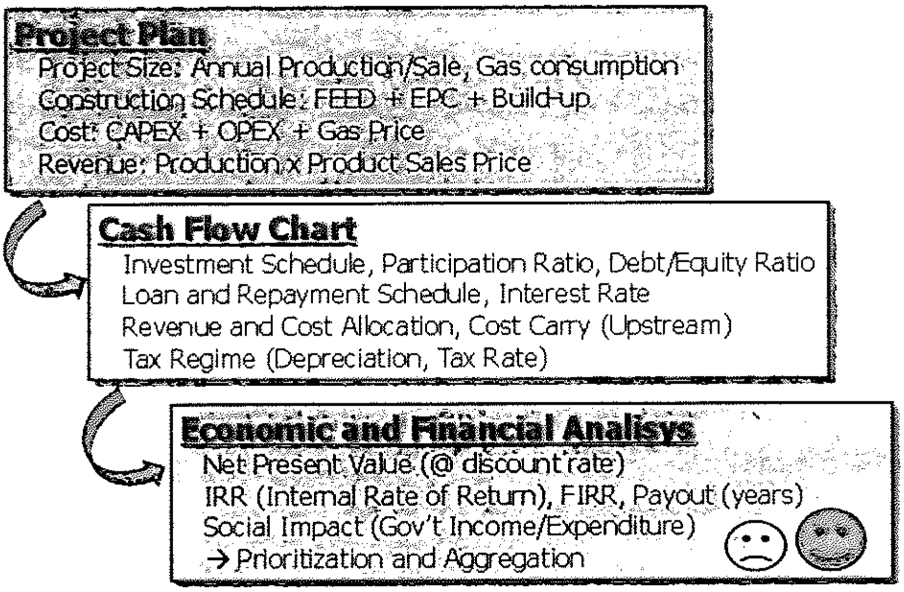


Figure 1.4-2 Method of Project Evaluation

1.4.5 Important Elements for Consideration

In the course of the study, various elements should be investigated carefully. Among them, key elements are as listed below:

1) Project Schedule

Project Formation (participants, commercial structure, operator, etc.)

FID and Construction Schedule (incl. inter-relation of chemical plants)

Upstream: Order of gas fields for production, Unitization, Sunk Cost

Market (including necessity of commercial build-up period)

2.) Gas Price

LNG for export = International Market Price

Gas for domestic market

Netback price of LNG (=Delivered LNG Price– Freight – Liquefaction Cost)

Upstream production cost including fair return (=Cost + Mark-up)

Affordable price (=Upstream Cost – Subsidy) that assures commerciality

3) Contract Regime

Government Participation

Cost Recovery and Profit Split

Loan and Repayment Scheme (Debt/Equity Ratio, Bullet Repayment, etc.)

4) Tax Regime

Depreciation

Tax (corporate tax, import/export duty, withholding tax, etc.)

Royalty, Fee, Subsidy

In addition to the above, though not quantitatively analyzed in this Study, the following issues also need to be considered in the course of formulating gas utilization plans.

Project Formation

Participants and commercial structure of the project

Role of shareholders

Organization during the construction phase and the production/operation phase

Requirement of Workforce

Workforce required by the project owner and EPC contractor

Job Categories, grades and headcounts

Engineer and Officer (University+ class)

Technician, Secretary/clerk

Skilled, Semi-skilled, Unskilled

Expatriates and nationals

5) Project Local Content

Equipment and materials to be imported

Equipment and materials to be locally procured

6) Institutional Preparation

Laws and Regulations (relating to business, immigration, environment, etc.)

Specific strategies and policies, social and political priorities

Project Special Regimes (Export processing zone, tax, subsidy, etc.)

The above study plan shall from time to time be reviewed in the course of the Study.

1.5 Joint Study in Tanzania

This study was conducted through interview and basic information collection for relevant parties and site visit as below;

a. Mtwara and Lindi: existing natural gas field, construction site of natural gas processing plant, pipeline, and candidate sites for LNG and gas processing plant.
b. Kinyerezi: construction site of LNG receiving terminal and Kinyerezi I Power Plant.

c. Bagamoyo: candidate site for Bagamoyo Industrial Park.
d. Site visit for local factories: MMI Steel Mills, Tanzania Breweries Ltd., and Panasonic Energy Tanzania.
e. Firewood and charcoal: field survey on firewood, charcoal, and LPG sale in Dar es Salaam.

Chapter 2 Overview and Outlook of the Global LNG

Chapter 2 Overview and Outlook of the Global LNG

2.1 LNG - An Ever-evolving Industry

In the past the global LNG market has doubled its size every ten years - from 50 million tonnes in 1990, 100 million tonnes in 2000, and 220 million tonnes in 2010. Now it is expected to have 400 million tonnes per year by 2020.

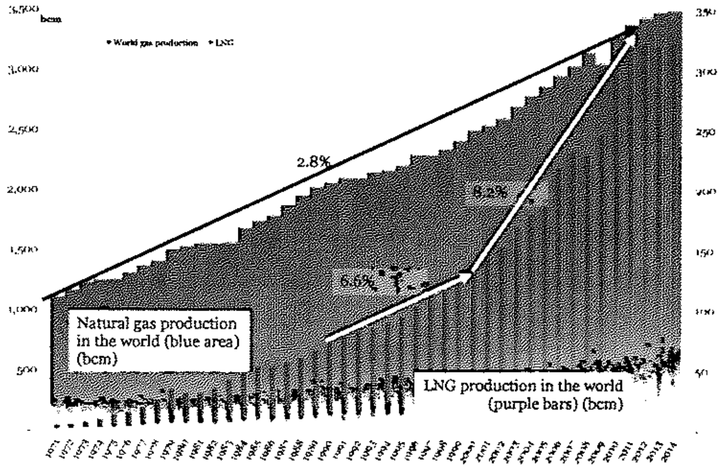
The LNG industry is relatively young, just celebrating its 50 year anniversary in October 2014. Thus it is quite natural for it to continue changing its shape and evolving.

The latest phase of expansion is unprecedented. We also saw huge expansion of the industry from 2009 to 2011. And it was also unprecedented at that time and the expansion caused a lot of changes.

Significant transformation in trading patterns is expected. During the current expansion phase, two production centres are expected increase presence: Australia and the United States. This is also expected to bring about another layer of flexibility and liquidity into the market.

LNG production projects have been capital intensive and newer projects are expected to be even more capital intensive.

2.2 LNG grows Faster than Gas as a whole



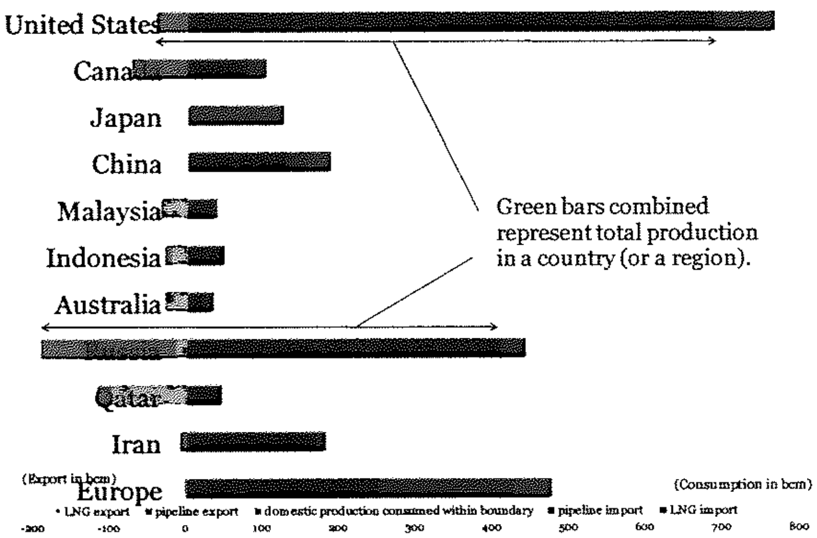
(Source) Compiled by IEEJ based on data from Natural Gas Information 2015, IEA, and The 2014 Natural Gas Year in Review - First Estimates, Cedigaz

Figure 2.2-1 Global LNG and gas production since 1970s

The chart describes growth of global LNG and total natural gas production from 1970. The blue area indicates total gas measured by the left axis. The purple bars indicate LNG measured by the right axis, which is one-tenth of the left one. In recent years the purple and blue have come closer to each other, which means about 10% of the total gas is now traded as LNG.

LNG has grown from almost nothing in 1970 to the current 10%, meaning that the growth rate for LNG has been much higher than that of natural gas as a whole, which in turn has been much higher than total primary energy demand growth.

2.3 The Global LNG and Gas World are dominated by Several Players



(Source) Compiled by IEEJ based on data from The 2014 Natural Gas Year in Review - First Estimates, Cedigaz

Figure 2.3-1 Global LNG and gas powerhouses in 2013

Then who are the largest in production, consumption, exports, and imports of natural gas and LNG? The countries indicated in the chart are the current largest countries in such categories.

The length of the line to the right from the zero line indicates individual market size. The green sections are covered by domestic production. The red sections include imports either via pipeline or in the form of LNG.

The length of the line to the left from the zero line indicates exports. The total length of the green sections indicates production.

Therefore the current two biggest gas producers are the United States and Russia, each producing about one-fifth of the global total natural gas. But their profiles are very different -

the United States consumes much more gas and Russia exports much more.

2.4 Existing and Expected changes in the LNG World

Changes in the LNG market can be summarized by specific aspect (Table 2.4-1)

LNG grows faster than natural gas as a whole and energy in general;

The Asia Pacific region evolves into more diversified combination of producers and consumers, supplemented by supply sources from outside;

More emerging markets are expected from Southeast Asia, Middle East and South America; and LNG's role are changing from a premium energy source in the last century to an essential way of developing gas markets around the world, as well as a more globalized market.

Table 2.4-1 Existing and expected changes in the LNG world

	Past	Present	Future
Expansion of the LNG market	Growth rates: LNG > gas as a whole > total primary energy	LNG continues growing faster than gas as a whole, although representing less than 10% of the total gas	Is LNG expected to expand its share in the total gas trade?
The hybrid structure of the Asia Pacific market	Simple trade flows from Southeast Asia and Australia to North Asia's traditional buyers	Emerging markets joins traditional markets as core buyers to underpin new supply project development	New emerging markets (Southeast Asia) develop into a production and consumption center
Emerging LNG markets in Southeast Asia, Middle East, and South America	Standalone and small-scale pipeline gas markets, with some LNG exports	Fast-track LNG import projects with LNGRVs and FSRUs to meet rapidly growing local gas demand	Gas market sizes catch up with and surpass those of some OECD members
Evolving roles of LNG	LNG provides long-term security of supply and demand. LNG represents a premium energy source.	LNG is a clean and affordable essential energy source. LNG transmits price signals between regional gas markets.	LNG promotes increasing use of natural gas (in different regions and applications). LNG acts as a balancer between markets.

But in this industry it has been always difficult to predict the future. Some specific perspectives often lead to unintended consequences.

Just ten years ago many people thought that the United States would be short of gas and importing a lot of LNG. But the expectation of higher gas prices over there encouraged huge domestic gas production, not only LNG production projects around the world targeting the United States. And, the Shale Revolution followed totally nullifying the previous views.

Then at this moment we are seeing declining oil prices, partly caused by expansion of liquid production in the United States, which in turn was caused by expectation of widening gaps between dry gas and oil prices.

While some people may expect an amply supplied LNG market for some years to come, others may be worried about slowing investment leading to supply shortage years later.

Table 2.4-2 Actions are sometimes based on uncertain assumptions in the industry

Generally-held perspective	Reactions by players	Consequences
Higher gas prices in the United States (held until 2007)	Investment in LNG production in the world Accelerated shale gas development in the United States	Major expansion in LNG supplying capacity Major increases in gas production in the United States
Widening gap between gas and oil prices (held until 2013)	Investment shifting from dry shale gas to liquid LNG export plans in the United States	Declining crude oil prices Leading to lower LNG prices linked to crude prices
Illusion of tight LNG market (held until early 2014)	Shifting away from LNG	Declining LNG prices
Buoyant outlook of Chinese and Asian gas demand	Accelerated LNG production investment	Chinese demand looking uncertain
Expected increase of LNG supplying capacity from 2014	Buyers reluctant to commit Review and delays of LNG investment	Concern over slower investment and possible shortage of capacity in the future

2.5 Important LNG Events in 2014 and 2015

Eleven important events in the global LNG industry in 2014 and 2015, which are also expected to have significant implications on the future of the industry, are summarized below:

Major LNG production capacity expansion is starting in the Pacific region;

LNG export projects are under construction in the United States;

Projects are not quick in Canada and East Africa, but potential is huge;

The pipeline deal between Russia and China may have impacts on pricing;

Russia's Yamal LNG project makes progress in marketing and other fronts;

Southeast Asia grows as an LNG consuming region;

More new LNG procurement deals are signed and buyers mull alliances;

Oil prices and spot LNG prices are coming down;

LNG demand is relatively calm but positive in 2014 after two years of little growth;

Japanese project finance dominates the LNG world; and

Greater flexibility in LNG trades is requested.

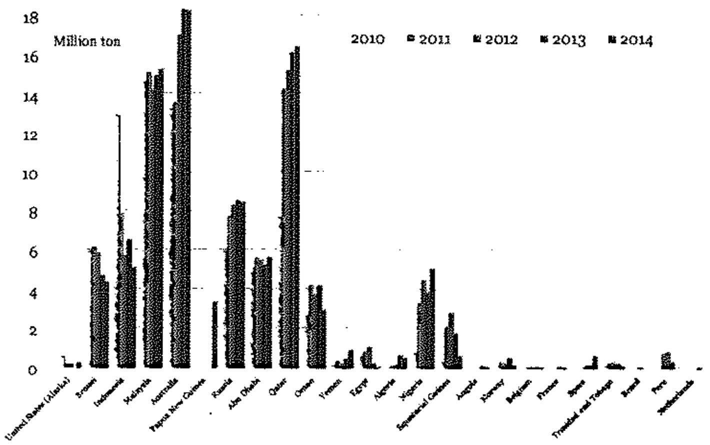
2.6 Additional 60 million tonnes is expected in Australia and Indonesia by 2020

The first item is the major expansion of capacity mainly from Australia. That country has already been a major supplier of LNG for more than 25 years from western states. Now in addition to other new projects in the west, large-scale LNG production projects are also under development in the eastern state of Queensland. Another notable feature is increasing buyers' equity participation.

Table 2.6-1 Additional 60 million tonnes is expected in Australia and Indonesia by 2020

Projects	Sponsors		mt	Offtakers (Bold with equity; Thinner letters indicate portfolio purchase)
QCLNG	BG	2015	8.5	**CNOOC, Tokyo Gas**, Chubu Electric, Singapore, Chile
APLNG	ConocoPhillips, Origin	2015	9	**Sinopec**, Kansai Electric
GLNG	Santos, Total	2015	7.8	**Petronas, Kogas**
Gorgon	Chevron, Shell, ExxonMobil	2015	15.6	**Osaka Gas, Chubu Electric, Tokyo Gas**, Kyushu Electric, JX, PetroChina, Petronet LNG
Wheatstone	Chevron, Woodside	2016	8.9	**Tepco, Kyushu Electric**, Chubu Electric, Tohoku Electric
Ichthys	Inpex, Total	2017	8.4	**Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas, Kansai Electric**, Tepco, Kyushu Electric, **CPC**, Kogas
Prelude	Shell, Inpex	2017	3.6	Tepco, Shizuoka Gas, Osaka Gas, Chubu Electric, JX, **Kogas**, CPC
Donggi Senoro	Mitsubishi Corporation	2015	2	Chubu Electric, Kyushu Electric, **Kogas**

Japan has seen major shifts in LNG supply sources in recent years in parallel with shifts observed in global LNG production. Currently Australia is the largest supplier of LNG to Japan and it is expected to continue being so in the foreseeable future. In recent years Japan has increased LNG imports from West Africa. No wonder East Africa is a promising candidate for Japan as a future source of supply.



(Source) Custom statistics

Figure 2.6-1 Japan's LNG supply sources in fiscal years 2010 - 2014

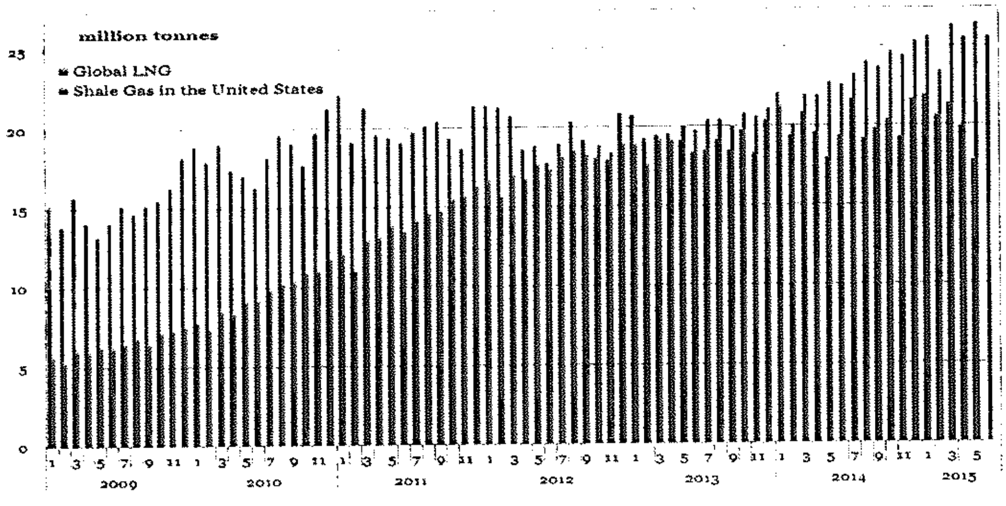
2.7 Another 60 million tonnes is expected from the United States

There are several LNG export projects in the United States that are already under construction or in the advanced stage of planning. Three projects targeting the Japanese market started construction in 2014. In the end Japan continues to play a pivotal role in realizing LNG project development.

Table 2.7-1 Another 60 million tonnes is expected from the United States

Projects	Sponsors	·	mt	Offtakers (**Bold with equity;** *Italic* letters indicate portfolio purchase)
Under construction				
Sabine Pass	Cheniere	2016	18	BG, Gas Natural Fenosa, Kogas, Gail
Primarily to Japan				
Cameron	Sempra, Mitsui & Company, Mitsubishi Corporation/NYK, GDF Suez	2018	13.5	Tepco, Tohoku Electric, Kansai Electric, Toho Gas, Tokyo Gas, CPC, Singapore
Freeport	Freeport LNG	2018	13.2	**Osaka Gas, Chubu Electric,** Toshiba, *Tepco, Kansai Electric*
Cove Point	Dominion, Sumitomo Corporation	2018	5	Tokyo Gas, Kansai Electric, Gail
Planned				
Corpus Christi	Cheniere	2019	13.5	Pertamina, Endesa, Iberdrola, Gas Natural Fenosa, Woodside, EDF, EDP

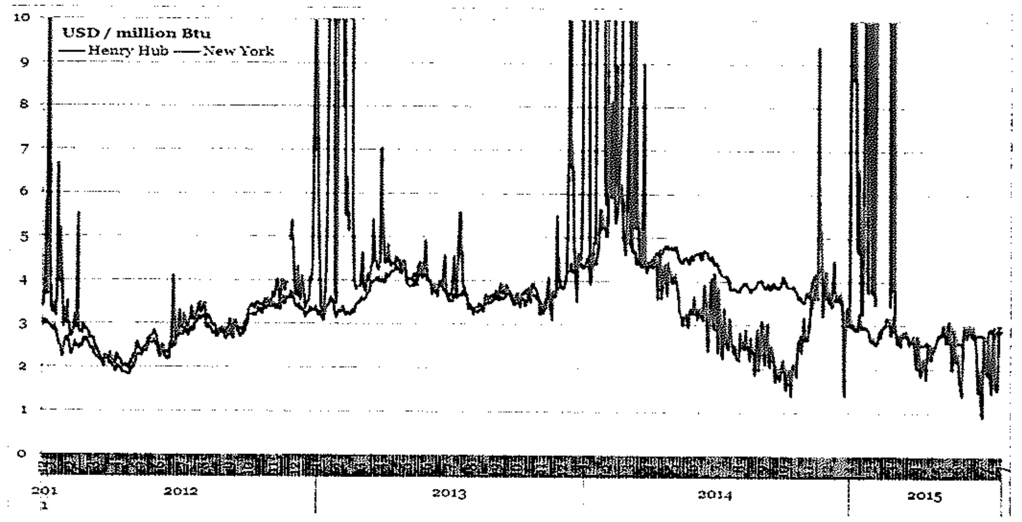
Expanding shale gas production is the driving force of the LNG projects in the United States. The shale gas revolution is pretty much still ongoing. The chart below shows monthly production of shale gas in the United States and global LNG in blue. In 2013 shale gas production became larger than the global LNG.



(Source) Compiled by IEEJ based on data from Energy Information Administration, the United States and trade information and Customs statistics

Figure 2.7-1 Shale plays in the United States produce more than the global LNG industry

Another example of ongoing features of the shale revolution is changing regional prices in the country (Figure 2.7-2). Spot gas prices in the United States have different movements depending on local market factors. Prices in New York (in red) in general fluctuate more wildly than those at Henry Hub. New York has been traditionally a large consumption centre while Henry Hub is close to traditional gas production centres. But in 2014 they took notably different courses - New York saw lower spot prices for an extended period due to increasing shale gas production from nearby Marcellus Shale.



(Source) Compiled by IEEJ based on data from data from the Energy Information Administration, the United States

Figure 2.7-2 Natural gas prices are still shifting in the United States

So Japan expects some LNG from the United States. Another question is how long it will take to transport. The Panama Canal is being expanded to be able to accommodate LNG tankers. As the projects are being constructed in the eastern side of the United States, potential saving by using the expanded canal from 45 days to 25 days will be significant. Recently the canal authority released the draft tariffs for 2016 including those for LNG tankers. The calculation has been streamlined and given the industry people some clear picture for the use of it.

Table 2.7-2 Draft tariffs for LNG tankers in 2016 proposed by the Panama Canal Authority

Bands in m^3	Laden	Ballast	Ballast (Roundtrip)
- 60,000	USD 2.50	USD 2.23	USD 2.00
- 90,000	USD 2.15	USD 1.88	USD 1.75
- 120,000	USD 2.07	USD 1.80	USD 1.60
Rest	USD 1.96	USD 1.71	USD 1.50

(Source) The Panama Canal Authority, 5 January 2015

2.8 East Africa and Canada are expected to provide the next wave

As Japan continues pursuing diversification of supply sources, expectations have been high for development in resource rich areas including East Africa and Canada. Although it is difficult to predict when but most likely Japan will need both as future sources of LNG.

Table 2.8-1 LNG development summary in East Africa

	Partners	mt	Developments in 2014
Tanzania	BG/Ophir, Statoil/ExxonMobil	10	Pavilion joins
Mozambique Area 1	Anadarko, Mitsui & Company, ENH, PTT, OVL/OIL		Non-binding offtake agreements for 2/3 of the Train 1 outputs
Mozambique Area 4	Eni, CNPC, Kogas, Galp, ENH		FLNG FEED

Table 2.8-2 Selected LNG projects in Canada

Projects	Partners	mt	Developments in 2014
Pacific Northwest	Petronas, Sinopec, Japex, Indian Oil, Petroleum Brunei	12	No FID Parallel FEEDs by JGC, etc. BC environmental permit
LNG Canada	Shell, PetroChina, Mitsubishi Corporation, Kogas	12	Project company is formed Chiyoda conducts FEED
Kitimat LNG	Chevron, Woodside	10	Apache is replaced by Woodside JGC consortium is awarded EPC

2.9 Russia advances gas sales strategy toward the East

Russia has two major deals with China:

One is pipeline supply from Siberia. Agreed volumes of supply are huge; and the pricing arrangement is also expected to have some impacts on LNG pricing in the Asia Pacific region.

Yamal LNG is expected to supply LNG from the Arctic region to China.

The Chinese gas market is still expanding rather rapidly, registering another 10% growth in 2014.

Table 2.9-1 Gas market developments between Russia and China

	Developments in 2014
Planned pipeline gas sales to China	Gazprom and CNPC agree on pipeline gas supply of 38 bcm per year (equivalent of 28 million tonnes per year) for 30 years beginning in 2018. The deal is said to be worth USD 400 billion, translated into USD 10 per million Btu. This may have implications on LNG prices in Northeast Asia The two sides also principally agree on additional 30 bcm via the Western Route in November.
Yamal LNG	With the FID in December 2013, the project has already secured sales to CNPC and Gazprom M&T . 9 ice-class LNG carriers have already been on firm orders Chinese and Russian banks provide financing
Chinese gas market	Another 10% growth in 2014 China produced 132.9 bcm, of which 1.3 bcm came from shale

2.10 Southeast Asia produces and consumes LNG

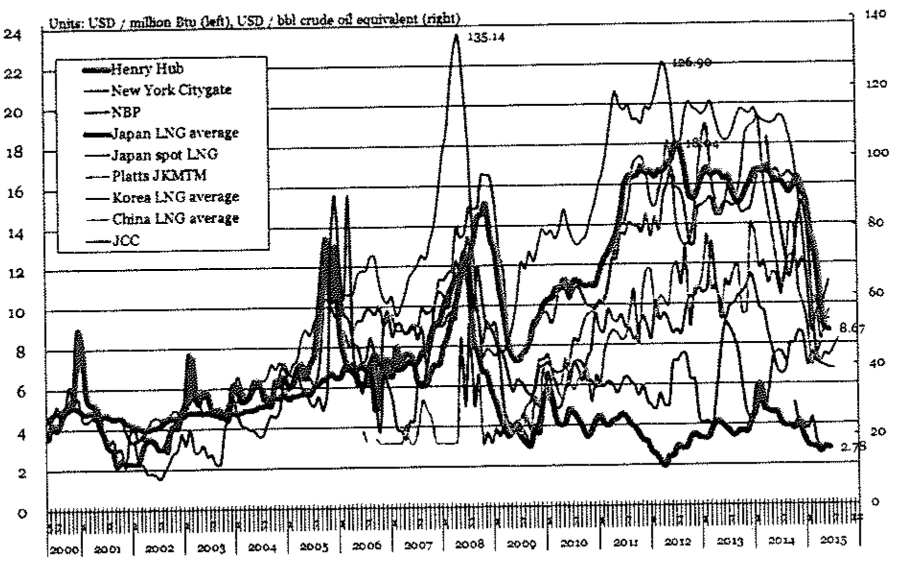
Japan continues relying on Southeast Asia as a major supply source. At the same time some countries are increasing LNG use. Indonesia and Malaysia continue supplying LNG to other countries, at the same time they began receiving LNG in their main gas consuming areas.

Table 2.10-1 LNG market developments in Southeast Asia

	LNG demand	LNG production
Indonesia	West Java opened an LNG terminal in 2012 Lampung opened another in August 2014 Arun's converted into an LNG receiving terminal in 2015 LNG purchase from Corpus Christi	Existing supply to the Bontang plant is expected to decline Some delays are anticipated for development of new feedgas sources to supply Bontang Donggi Senoro LNG starts operation in 2015 Tangguh expansion in 2019
Malaysia	Melaka started in 2013 Pengerang due in 2017 Procurement from PNW LNG	Petronas FLNG1-2 and Malaysia LNG 9 are under construction
Thailand	Map Ta Phut started in 2011 Term deliveries from Qatar started in 2015	
Singapore	Jurong started in 2013	

2.11 Regional prices walk in different paths

Figure 2.11-1 shows representing gas prices around the world from 2000 to 2014. Since 2008 the gap between regional prices have been widening and persisting.

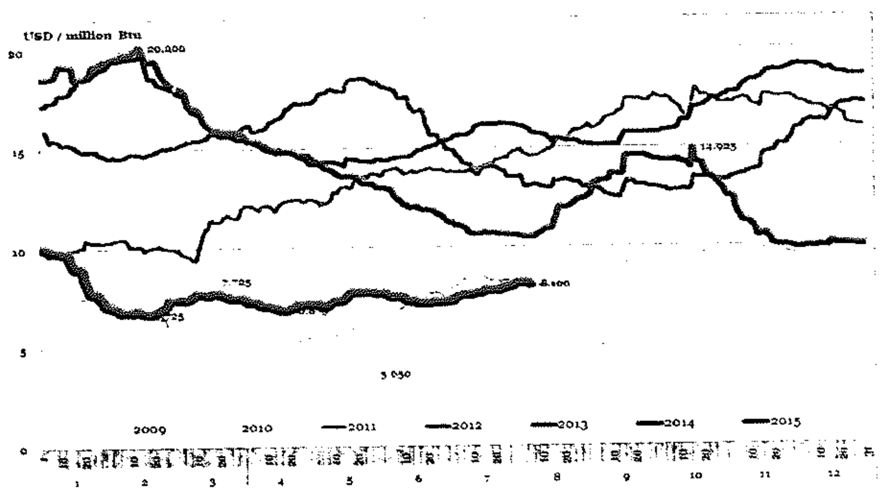


(Source) Compiled by IEEJ based on data from custom statistics of countries, the Energy Information Administration, Energy Intelligence and Platts

Figure 2.11-1 Regional gas prices

While majority of LNG is traded under long-term contracts, spot and short-term cargoes are playing a more important role in recent years.

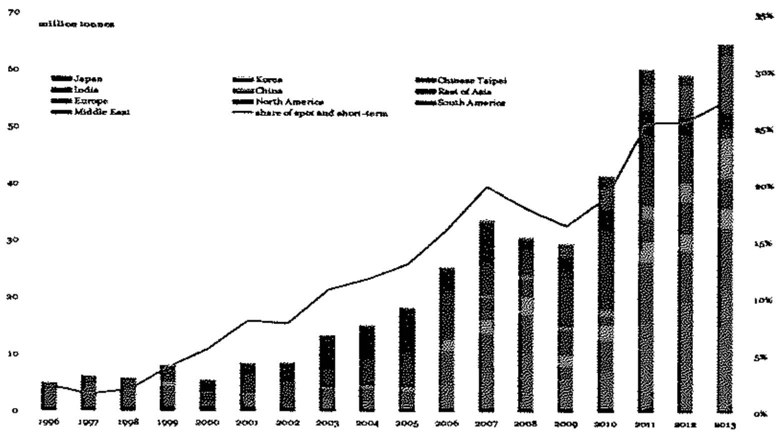
Some information service companies have provided spot price assessments. Those have not established as reliable price benchmarks yet, as the market is not yet liquid enough. As actual transactions are still scarce and few, the assessments are mostly based on notified offers and bids. Having said that, they can be viewed as some indications of market sentiments. In 2014 it was expensive, hitting 20 dollars in February. In 2015 at one point it was less than 7 dollars and is still much lower than previous years.



(Source) Compiled by IEEJ based on data from Platts LNG Daily

Figure 2.11-2 Spot LNG assessment prices

Growth of short-term trades is accompanied with the growth of the overall market, as well as diversification of sources and markets. More than 60 million tonnes or 1/4 of the total LNG is traded under short-term arrangements.



(Source) Compiled by IEEJ based on data from GIIGNL

Figure 2.11-3 Spot and short-term LNG volumes

Also supply routes are diversifying. In 1998, the markets were relatively simply divided.

The flows in 2014 were rather complicated. Traditional supply sources in the Asia Pacific and Middle East regions continued supplying to the markets in the East, while the suppliers in the Atlantic region also supplied some LNG to the East. Additionally some European importers re-exported LNG after imports.

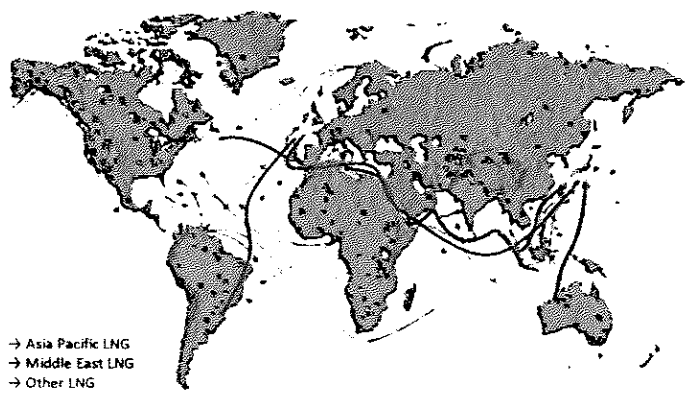
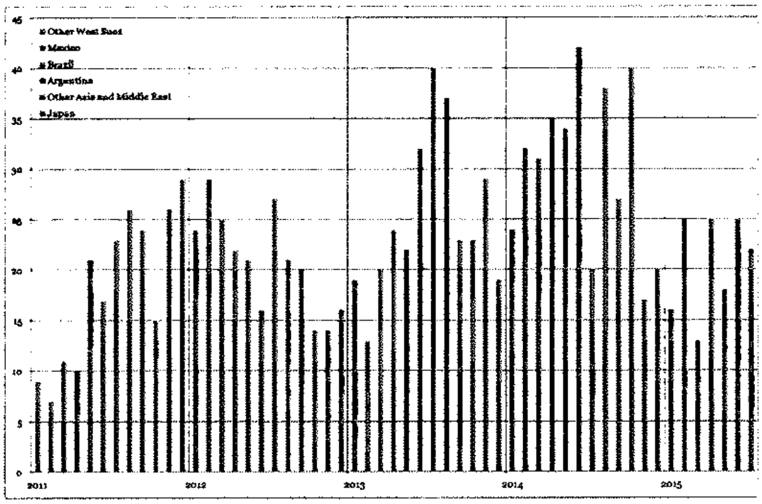


Figure 2.11-4 LNG trade flows in 2014

If we look at the cargo movements by month, they also change quite significantly depending on seasonable weather patterns and other factors. Japan increased spot purchases immediately after the nuclear crisis in 2011 (shown in blue) but decreased gradually in 2012 as it shifted some incremental purchase into contract arrangements. In 2013 and 2014, Latin American importers increased their presence in the spot LNG market.



(Source) Compiled by IEEJ based on data from ICIS Heren Global LNG Markets and Platts LNG Daily

Figure 2.11-5 Number of spot LNG cargoes by destination

Many people in the industry used to say, especially until early 2014, that the LNG market would be tight until 2015. They often fail to distinguish between the global LNG market as a whole and the short-term LNG market. The notion of tightness itself may have had effects to raise negotiated prices. Because of this, the notion of market tightness is part of the structural problem of expensive LNG prices.

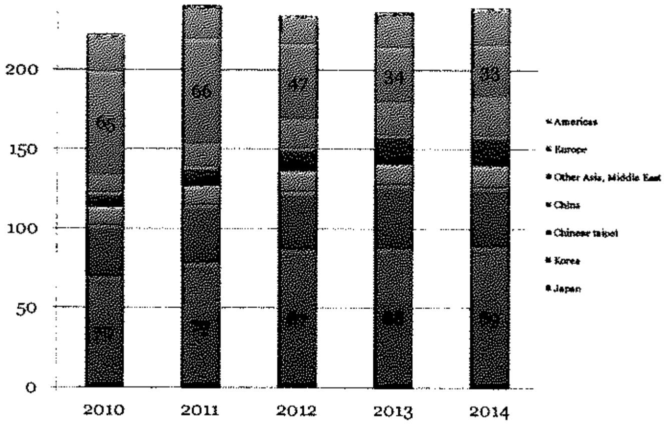
Such arguments of tightness of short-term LNG markets, often found in commercial media and sellers' comments, could give undue supports to such LNG sellers, leading to unrealistically high offering prices.

The overall balance in the LNG market did not show any signs of tightness, even though some supply disruptions are observed from the Atlantic region producers. Lost LNG volumes in European markets in recent years have been more than offset by Russian pipeline gas supply, as well as reduction of overall gas demand.

Some decreasing liquidity of short-term LNG cargoes is sometimes observed leading to seasonal imbalances.

2.12 2012 - 2014 did not see significant growth of the LNG market

Even though major expansion is expected to begin, the past few years have been quite an unusual time of lower growth for the LNG industry caused by combination of factors of supply disruptions in some Atlantic region sources and more importantly disappeared LNG demand in Europe. Part of this demand destruction in Europe has been also caused by the illusive notion of LNG market tightness and higher prices.

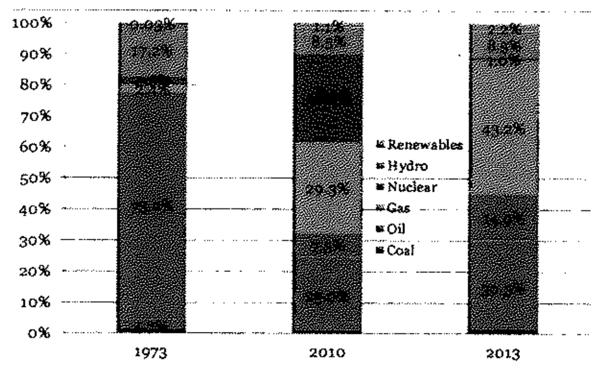


(Source) Compiled by IEEJ based on data from custom statistics of countries and data from GIIGNL

Figure 2.12-1 Global LNG import in 2010 - 2014

2.13 Japan continues to be a key to the LNG business

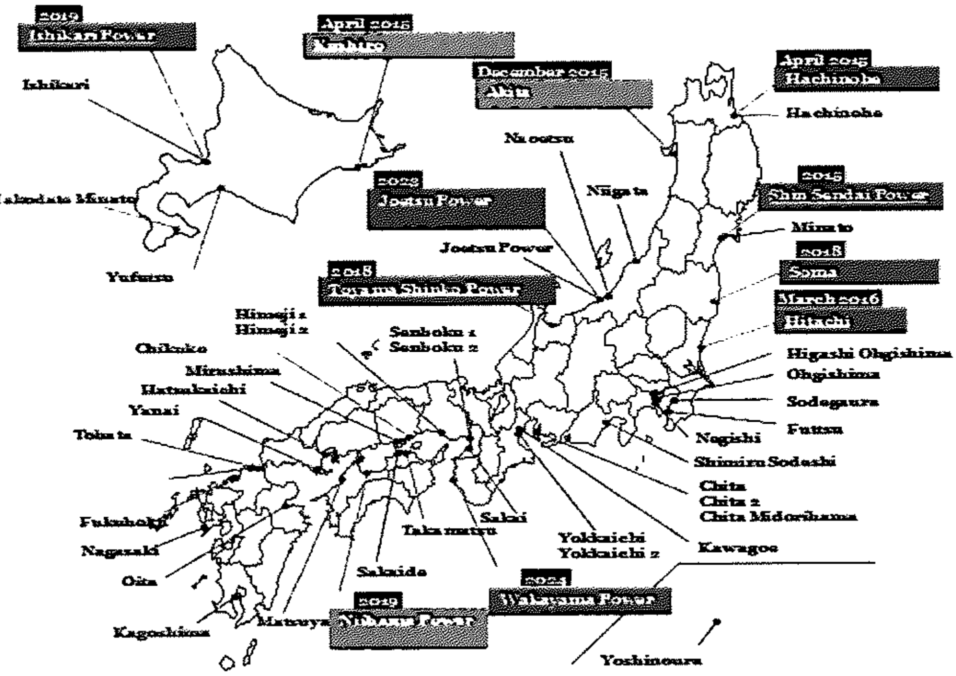
What have happened to Japan during the history of LNG market growth? In fact Japan currently consumes one third of the global LNG production and has contributed significantly to the growth of the industry. During the period, the share of LNG in the Japan's energy mix grew from almost zero to more than 20% today. Especially for power generation, after the oil shocks in 1970s, gas was promoted along with nuclear power as an important alternative. And after the nuclear crisis in 2011, the shift to gas has been further accelerated.



(Source) "EDMC Energy Trend", IEEJ monthly publication

Figure 2.13-1 Japan's power mix in the past and present

For the moment some anticipated nuclear restarts will likely reduce LNG consumption, while the country continues to expand LNG infrastructure. Now not only the nation's city gas and electric power utility companies, oil companies and additional smaller utility companies are investing in LNG receiving terminals. Consequently, depending on competitive advantages among different energy sources, the country will be in a position to take advantage of more competitive LNG supply in the future.



(Source)IEEJ

Figure 2.13-2 Japan's LNG receiving terminals

Table 2.13-1 Project financing deals in 2014

	Amounts	Lenders
Cameron	USD 7.4 billion	JBIC, Bank of Tokyo-Mitsubishi UFJ, Sumitomo Mitsui Banking Corporation, Mizuho Bank, Sumitomo Mitsui Trust Bank, Mitsubishi UFJ Trust and Banking, Norinchukin Bank, Shinsei Bank, Aozora Bank, Shinkin Central Bank, Chiba Bank, Shizuoka Bank
Freeport 1	USD 4.369 billion	JBIC, Bank of Tokyo-Mitsubishi UFJ, Sumitomo Mitsui Banking Corporation, Mizuho Bank, Sumitomo Mitsui Trust Bank, Mitsubishi UFJ Trust and Banking, ING Bank N.V., Tokyo Branch
Donggi-Senoro	USD 1.527 billion	JBIC, Bank of Tokyo-Mitsubishi UFJ, Mizuho Bank, Sumitomo Mitsui Banking Corporation, and other commercial banks, KEXIM
Ichthys - Kansai Electric Power's share (Project total)	USD 356 million (USD 17 billion)	JBIC, commercial banks

Because LNG projects have been capital intensive and needed several years to construct, even after several years of conceptual and planning stages, long-term reliable sources of financing have been very important. Those (on the table above) are project financing deals concluded in 2014 for LNG projects. The deals were led and arranged by JBIC and Japanese commercial banks.

In addition to those familiar names in this business some new financial institutions are entering LNG project financings. Appetite from those Japanese banks is expected to be strong in the years to come.

The Japanese government is expected to be more supportive in LNG project development. The Strategic Energy Plan approved by the Cabinet in April 2014 states measures to support those projects:

"Section 3, Subsection 1 Policy measures to stable procurement

1. . . . Strengthening relationship with new resource countries and promoting upstream participation by Japanese companies

To promote more upstream participation by Japanese companies, the government should make efforts to strengthen diplomatic ties with resource-rich countries and enhance functions and roles of JOGMEC to provide risk money.

3. Improving contract terms and conditions to reduce procurement costs

Measures should be undertaken to improve terms and conditions in LNG procurement, including not only pricing but also flexibility of transactions and equity stakes in supply projects. . . More flexible conditions should include elimination of destination restriction clauses in free-on-board (FOB) contracts. "

As for the specific emphasis on improving contract conditions and making LNG transactions more flexible, the government has made progress in bringing the issue into focus in the international arena including the G7 summit in Brussels on 5 June 2014 (See the declaration quoted below), to say nothing of the LNG Producer - Consumer Conference in Tokyo in November:

"8. We will also:

Promote a more integrated Liquefied Natural Gas (LNG) market, including through new supplies, the development of transport infrastructures, storage capabilities, and LNG terminals, and further promotion of flexible gas markets, including **relaxation of destination clauses** and producer-consumer dialogue." (The Brussels G7 Summit Declaration on 5 June 2014)

2.14 Conclusion

A larger and more flexible LNG market is expected with capacity expanding to 400 million tonnes globally by 2020. Demand for the fuel is expected to grow but with significant uncertainty. Therefore greater flexibility is not only expected but is necessary.

Although the market is accompanied with more uncertainty and is expected to be more difficult to manage, the greater market is expected to provide more reward. New reality of lower crude prices and market calls for more competitive LNG prices pose challenges - but they can be overcome through cooperation between suppliers and consumers.

Chapter 3 Natural Gas Development: Upstream Sector

Chapter 3 Natural Gas Development: Upstream Sector

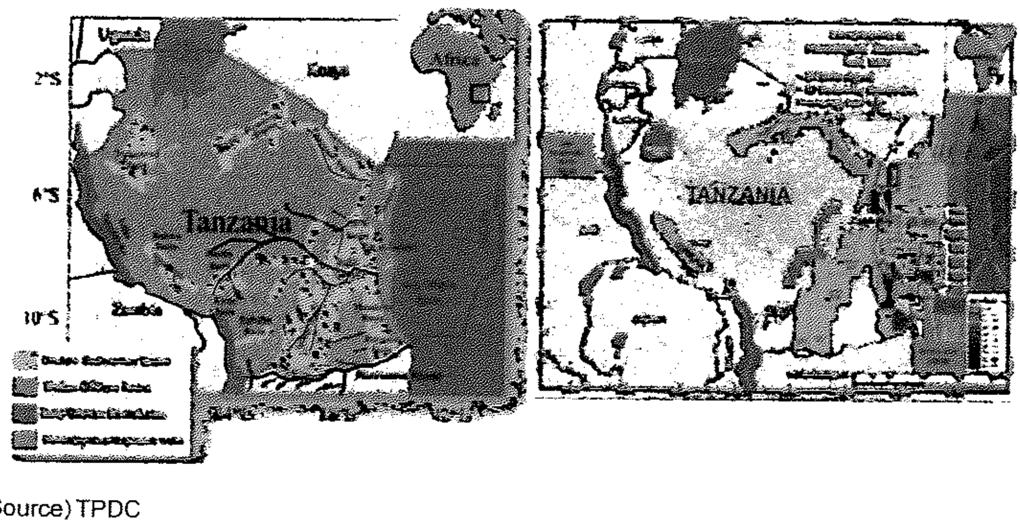
3.1 Oil and Gas Exploration in Tanzania

3.1.1 Outline of Geological Setting

The development of the East African sedimentary basins is linked to the Gondwana break-up and separation of Madagascar from East Africa. Rifting and drifting of these subcontinents led to the creation of sedimentary basins and deposition of sediments. Four main sedimentary basins are recognized in Tanzania; inland rift basins, coastal basins, shelf and shallow offshore basins and deep offshore basins as shown in Figure 3.1-1.

a. Coastal basins include Ruvuma, Mandawa and Tanga.
b. Inland rift basins include Selous, Kilosa Kilombero, Pangani, Eyasi-Wembere, Malagarasi, Lake Tanganyika, Rukwa, Ruhuhu and Lake Nyasa. Some of these basins contain Permian-age sediments.
c. Shelf and shallow offshore basins include Songo Songo, Pemba-Zanzibar and all offshore basins up to 200m water depth.
d. Deep offshore basins include all sedimentary basins in territorial waters in depths more than 200m.

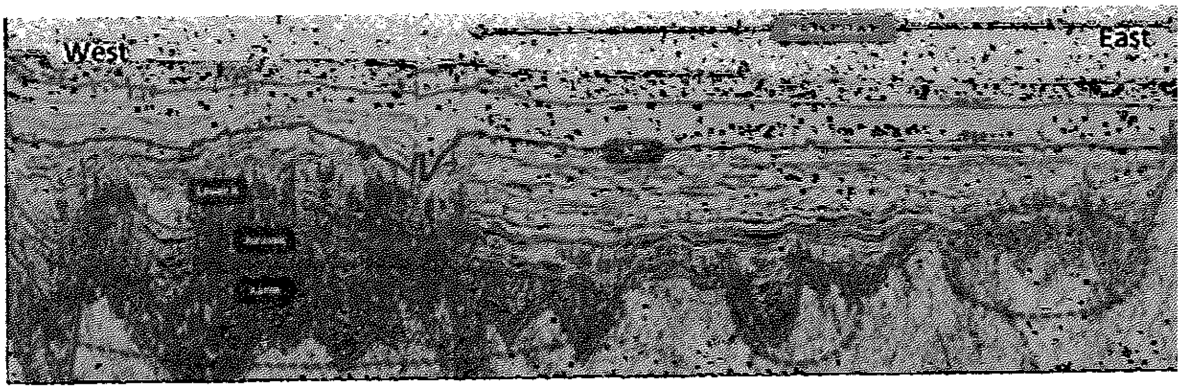
Natural gas discovered in the shelf and shallow offshore basins, namely Songo Songo and Mnazi Bay gas fields, are presently in production, while huge natural gas deposits have been discovered in the deep offshore basins. No oil field has been discovered in Tanzania, while exploration in the Great Rift Valley and further deep offshore is expected to find oil.



(Source) TPDC

Figure 3.1-1 Sedimentary Basins in Tanzania and Exploration Blocks

Present main exploration targets are the offshore deepwater gas play. According to TPDC, the west-east cross section in the middle part of the Ruvuma Basin indicates that possible kitchens and hydrocarbon generation are inferred from the PSDM (Prestack Depth Migration) and chimney analysis as shown in Figure 3.1-2. PSDM and vertical migration analysis also shows possible migration pathways from the kitchen. The geothermal gradient of 35-38 degree C was found to be sufficient to explain the gas discovery trend in the west side and with possible liquid hydrocarbons in the eastern side.



(Source) TPDC

Figure 3.1-2 Ruvuma Basin

3.1.2 Exploration History

In Tanzania, the first sizable natural gas discovery was made in 1974 by Agip at the Songo Songo gas field located 200 km south of Dar es Salaam was discovered across an area extending from shore side to shallow offshore of the Songo Songo Island. With intensive appraisal of the discovery, various development options were examined. However, it took decades to reach the final development decision as explained below. Then, Mnazi Bay gas field was discovered by Agip in 1982 in the estuary region of the Ruvuma River located in the most southern part of the country, while the principal objective was to find oil in Cretaceous layers. The Mnazi Bay 1 well successfully tested gas in Tertiary sands, but Agip relinquished the license due to lack of gas market.

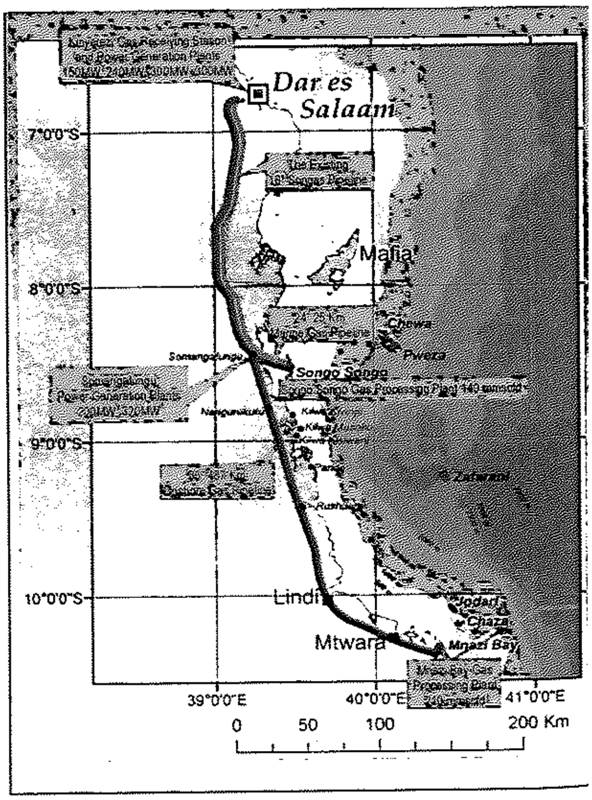


Figure 3.1-3 Natural Gas fields and Pipelines

In 2001, the World Bank decided to support the development of the Songo Songo gas field and related gas utilization facilities. In 2004, the gas field and the gas system were completed to start supplying fuel for power generation and industrial use in the Dar es Salaam district. In addition, to significantly increase the gas supply for domestic requirement, a 534 Km pipeline with the capacity of 784 Bcf per year was completed in the summer of 2015 connecting the Mnazi Bay gas field to Dar as Salaam, upon completion of which a newly constructed Kinyerezi I Thermal Power Station commenced its operation. Capacities of natural gas processing plants and pipelines as at August 2016 were as shown in Table 3.1-1.

Table 3.1-1 Natural Gas Processing Plant and Pipeline: as at August 2016

Gas Processing Plant		Capacity
		MMcfd
Old	Songo Songo	110
	Mnazi Bay	10
New	Songo Songo	140
	Madimba (Mtwara)	210
Total		470

Gas Pipeline	Distance	Capacity
	km	MMcfd
Songo Songo to Dar es Salaam	232	105
Mnazi Bay to Mtwara	27	70
NNIGP (Madimba to Dar es Salaam)*	534	784

(Note) National Natural Gas Infrastructure Project
(Source) TPDC

Further, as mentioned above, presence of deepwater gas fields had been confirmed with an estimated reserve of 47.13 trillion cubic feet (Tcf), on the basis of gas initial in place according to the estimates made by the Tanzania Petroleum Development Corporation (TPDC) at the end of December 2015. Since the above reserve size is far larger than that of the existing gas fields onshore and shallow offshore (10.118 Tcf, same basis as above), high expectations are held on commercial development of an LNG project in Tanzania just like in Mozambique.

In view of the readiness of supply, gas fields in Tanzania may be divided into two groups, that is, shallow water gas fields already in production and deepwater gas fields in the exploration and appraisal stage. Only shallow water fields can be considered for gas supply before 2025. In order to establish a development and utilization plan of the country's robust gas reserves, the government of Tanzania has undertaken compilation of the Natural Gas Utilization Master Plan (NGUMP: Natural Gas Utilization Master Plan); this Study aims to review the draft plan.

3.2 Natural Gas Resources

According to Tanzania Petroleum Development Company (TPDC), Tanzania's estimated gas initial in-place (GIIP) as of December 2015 is 57.25 Tcf, of which 10.12Tcf comes from onshore (including shallow water) fields, and 47.13 Tcf comes from deepwater fields as shown in Table 3.2-1.

This estimate includes the new onshore gas discovery in the Ruvu basin disclosed in February 2016. The gas field reportedly contains 2.17 Tcf of GIIP and is located only 30km west of Dar es Salaam. Being an onshore gas field relatively easy to develop and because of its proximity to the demand center, the Ruvu basin discovery will join the natural gas supply line-up within a short period of time.

The new estimate of the combined GIIP has significantly increased from 37.5 Tcf as of June 2013, and it is mostly attributable to active exploration and delineation activities in the deep water areas.

Table 3.2-1 Natural Gas Resources in Tanzania: December 2015

	Gas field	GIIP (P 10)	Recoverable Reserves
		Tcf	Tcf
Onshore and Shallow Water	Songo Songo	2.500	0.734
	Songo Songo Main		
	Songo Songo North		
	Songo Songo West		
	Kiliwani	0.070	
	Mnazi Bay	5.000	0.820
	Mkuranga	0.200	
	Mtwara-Ntroya	0.178	
	Ruvu Basin	2.170	
	Sub-total	10.118	
Deepwater	Block 1,3 & 4	22.000	16.000
	Block 2	21.000	
	Sub-total	47.130	
Grand total		57.248	

(Source) MEM/TPDC. Break-down of deepwater field reserves among blocks and recoverable reserves are the information separately obtained through hearing, which are not precisely comparable with other numbers for GIIP.

3.3 Shallow Water and Onshore Gas Fields

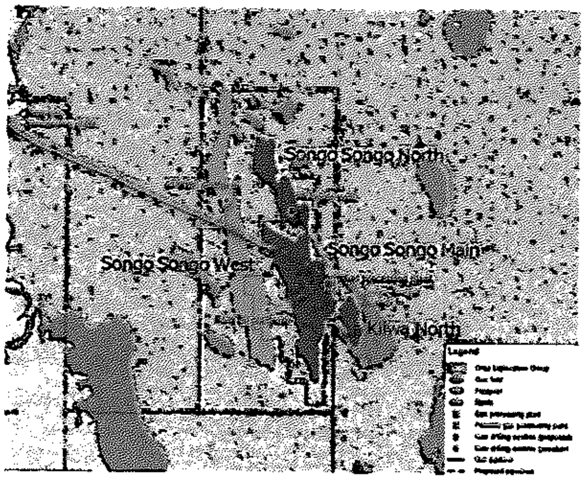
The shallow water gas fields are mainly Songo Songo and Mnazi Bay. In addition, natural gas has been discovered at Mkurannga, Kiliwani, Mtwara-Ntorya structures. However, GIIP of these structures are one digit smaller than GIIP of Songo Songo and Mnazi Bay. These minor discoveries located along or near the gas pipeline may be put in production but they are not significant at present. Currently, PanAfrican is carrying out a project to increase Songo Songo's production from the current level of 90MMcfd to 190 MMcfd (plus 20 MMcfd from Kilwa North), while, Maurel & Prom is carrying out a project to increase Mnazi Bay's production from 2 MMcfd to 130MMcfd. These projects are planned to complete in a few years. Both companies have a plan to further increase production, i.e. 260 MMcfd for Songo Songo and 200-210 MMcfd for Mnazi Bay. In addition, an onshore gas field was discovered in 2015 in the Ruvu basin near Dar es Salaam, which is presently under delineation.

3.3.1 Songo Songo Gas field

1) Current Status

The Songo Songo gas field was discovered in 1974 by Agip (Africa) Ltd (presently ENI), but the Italian company gave up the gas field as not being commercially feasible. In 1995, the Tanzanian government opted for implementation of the Songo Songo gas-to-power project with the principal goal to provide reliable source of low cost electricity. The World Bank made the final decision to support the project in 2001. The project was started by a consortium of various foreign/local joint ventures ranging from upstream through gas utilization. The gas field was developed by PanAfrican Energy Tanzania Limited, an arm of ORCA Exploration Inc. Group, and became on stream in June 2004. Production in 2013 was 35 billion cubic feet (Bcf) or 96 million cubic feet per day (MMcfd).

The Songo Songo cluster comprises Songo Songo Main, which is presently producing, Songo Songo North (SSN), where natural gas has been confirmed by drilling but not producing yet, and Songo Songo West (SSW), a promising prospect for future appraisal. There is another small gas field Kilwa North operated by Ndovu Resources (Animex/Solo Oil) to start production soon. The main producer of Songo Songo is upper cretaceous sand stone, and the average recovery factor is about 75-80%.



(Source) Ministry of Energy and Mining

Figure 3.3-1 Songo Songo Gas field

2) Gas Resources

The gas initial in place (GIP) of the SS+SSN+SSW is presently estimated at 2.5 Tcf. The recoverable reserve of SS+SSN at a probability of 50% (P50) is estimated to be 734Bcf at December 2014, according to TPDC. The recoverable reserve of SSW is estimated at 0.45 Tcf, according to the operator.

3) Additional Exploration and Development Plan

In line with the construction of the new gas pipeline from Mtwara to Dar es Salaam, a new branch line from Songo Songo is also being constructed. There are 11 production wells at the Songo Songo main structure. The operator PanAfrican plans to workover corroded wells and add the 12th producing well to increase the gas production from the present 92MMcfd (early 2015) to 190MMcfd simultaneously with the start-up of the new pipeline. Presently a new gas sale agreement is under negotiation. The operator explains that this production rate will be maintained up to 2026 when the present PSA expires. However, it will start a steep decline after then. With some anxiety on earlier decline, PanAfrican is planning to carry out evaluation of the Songo Songo North where gas has been confirmed already; running seismic survey and drilling an appraisal well. PanAfrican expects that, if SSN is put in production, gas production could be raised by 70MMcfd from 2019. The peak production will reach 260 MMcfd, but the production will start decline in 2026.

Thus the operator wishes to appraise a nearby prospect Songo Songo West (SSW). According to PanAfrican, SSW is a geologically similar structure to SS. However, essential factors which determine the accumulation of gas, such as gas water contact level and fault system are totally unknown because no wells were drilled in this structure yet. If these factors are favorable, 1Tcf of GIIP is expected. In the other way around, if these factors are not favorable, the present estimate of GIIP of Songo Songo will be halved. As such, it is important to note that an operator like PanAfrican always takes risks in oil and gas upstream business

3.3.2 Mnazi Bay Gas field

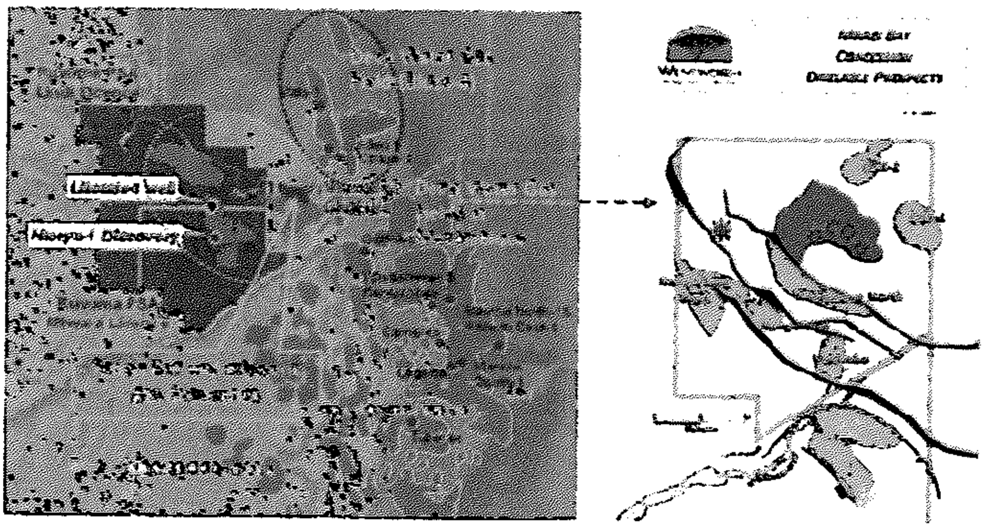
1) Current Status

The Mnazi Bay gas field is located southernmost part of Tanzania at the estuary of the Ruvuma River, which defines the border with Mozambique. The gas field was discovered in 1982 by Agip, and likewise with Songo Songo, it was relinquished.

In 2002, Calgary-based Artumas Group proposed the Mtwara Gas-to-Power Project to the Tanzanian government. The well Mnazi Bay 1 was re-entered in 2005 and flow tested. The consortium of Maurel & Prom Exploration Production Tanzania Ltd (M&E, operator), Wentworth Resources Ltd (ex Artumas) and TPDC commissioned the project in 2007. However, the production of the Mnazi bay gas filed has been limited only at 2 MMcfd due to lack of local demand. Presently, it is supplying a small quantity of natural gas (687 MMscf in 2013) for a tiny 18MW local power plant via pipeline. As shown in Figure 3.1-3, a new natural gas pipeline was constructed under the Natural Gas Infrastructure Project to transport the gas from Mnazi Bay to Dar es Salaam. After its completion in the summer of 2015, production from the Mnazi Bay will increase to 210MMcfd (70Bcf per year).

2) Gas Resources

According to TPDC, the gas recoverable reserve of the Mnazi Bay at P50 is 820 Bcf. M&P explains that this number is for the structures under development to accommodate the requirement for the new pipeline. On the other hand, the GIIP of the Mnazi Bay gas field is widely announced to be 5Tcf. This published figure is likely to be overstated considering the present progress of exploration. In this area, prospects/leads other than the Mnazi Bay are not drilled yet. With the present small production amount, it is difficult to fully evaluate the productivity of the reservoir too. Reliable reserve estimate would be obtained only when field production increases to the full extent and data accumulate sufficiently.



(Source) TPDC, Wentworth

Figure 3.3-2 Mnazi Bay and Adjacent Gas Fields

3) Development Plan

In order to prepare sufficient supply of natural gas for the Natural Gas Infrastructure Project, Maurel & Prom is drilling three additional production wells (Mnazi Bay-2, -3 and Msibati-1) and conducting workover of three or four wells; the total number of producing well will increase to seven. TPDC is constructing a new gas processing plant to accommodate the incremental production. All the incremental gas will be sold to and marketed by TPDC.

In addition, M&P wishes to expand its exploration activities to adjacent prospects (OSX-1 and OSX-2) once gas sale agreement is confirmed and assurance of gas price is established for the future additional production. They are located just offshore the existing gas processing plant and, if successful, could be tied to the new gathering system under construction.

3.3.3 Ruvu Basin Gas Field

On February 25, 2016, the Ministry of Energy and Minerals disclosed that an onshore gas field was discovered in Ruvu basin, about 50km west of Dar es Salaam, by UAE based Dodsal Hydrocarbons and Power. So far Dodsal has drilled three wells at Mbuyu, Mtini and Mambokofi in the exploration area in Coast Region and the resource is reported to be 2.17Tcf. The company said that "Exploration is still ongoing and we are optimistic of striking more natural gas reserves in the Ruvu Block"[1]

3.4 Deepwater Gas fields

3.4.1 Current Status

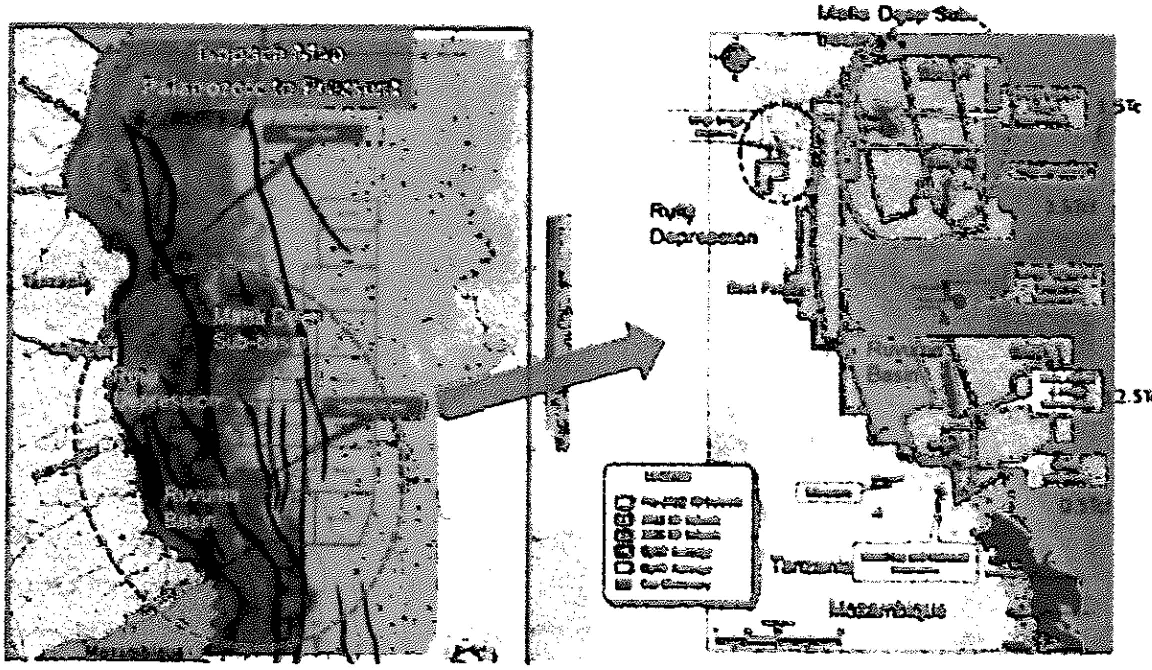
Substantial gas discoveries made in the Ruvuma basin deepwater blocks of Mozambique has opened up the east African gas era and stimulated exploration in the Tanzanian deepwater. In 2010, BG/Ophir group made a significant gas discovery at the Pweza-1 well drilled in Block-4 in 1,400m deepwater. Following this, extensive exploration activities have been conducted by BG Group and Statoil/ExxonMobil quite successfully. Out of 17 wildcat wells, 15 wells were gas discoveries as shown in Table 3.4-1.

Table 3.4-1 Exploratory Drilling in Deepwater Blocks

	Well	Block	Company	Drilled	TD (m)	WD	Result
1	Pweza-1	4	Ophir	2010	4082	1400	Gas
2	Chewa-1	4	Ophir	2010	3076	1315	Gas
3	Chaza-1	1	Ophir	2011	4600		Gas
4	Zeta-1	5	Petrobras	2011	4832		Dry
5	Zafarani-1	2	Stat Oil/ExM	2012	5150		Gas
6	Jodari-1	1	BG/Ophir	2012	4490	1153	Gas
7	Mzia-1	1	BG/Ophir	2012	4860	1639	Gas
8	Lavani-1	2	Stat Oil/ExM	2012	3850		Gas
9	Papa-1	3	BG/Ophir	2012	5575	2186	Gas
10	Lavani-2	2	Stat Oil/ExM	2012	5270		Gas
11	Zafarani-2	2	Stat Oil/ExM	2012	3039		Gas
12	Jodari-S	1	BG/Ophir	2012	3441		Gas
13	Jodani-N	1	BG/Ophir	2012	3389		Gas
14	Pweza-2	4	Ophir	2013			Gas
15	Pweza-3	4	Ophir	2013			Gas
16	Mzia-2	2	Stat Oil/ExM	2013	4820		Gas
17	Tangawizi	2	Stat Oil/ExM	2013	3030		Gas
18	Mzia-3	2	Stat Oil/ExM	2013			Gas
19	Ngishi-1	4	BG/Ophir	2013	2700+	1301	Gas
20	Mkizi-1	1	BG/Ophir	2013	3000+	1300	Gas
21	Mronge-1	2	Stat Oil/ExM	2013	5000+	2511	Gas
22	Binzari-1	2	Stat Oil/ExM	2013			Gas
23	Mlinzi	7	Dominion	2013			Dry

(Source) TPDC

[1] http://www.naturalgasasia.com/more-natural-gas-discovered-in-tanzania-17794



(Source) TPDC

Figure 3.4-1 Deepwater Gas Discoveries Offshore Tanzania

As is mentioned in 3.4.2, gas discovery is enormous in the Tanzanian deepwater too. BG Group and Statoil are presently carrying out studies on deep-water gas field development, with a view to supply feed gas to an LNG plant to be newly built, one train of 5Mtpa each. The Final Investment Decision (FID) is envisioned in 2017 and commencement of commercial production is planned for 2022. BG Group will probably build another one train or two sometime after the first one is complete, as it is necessary to produce from each gas field discovered in different blocks to recover the sunk cost effectively.

There are many oil and gas fields around the world, which are developed in the water depth of more than 300 meters, and the development in the deep water exceeding 1,000 meters is not an exception now. However, it is true that deep water oil and gas development dictates a big challenge, and its severity will grow when water depth increases. The selection of a subsea production system is essential because it not only accounts for large portion of capital expenditure, but also affects the reliability of production operation. BG Group and Statoil are now carrying out Pre-FEED with regards to subsea production system.

3.4.2 Gas Resources

BG Group has drilled sixteen exploration and appraisal wells in Blocks 1, 3 and 4, and found a significant amount of gas at the structures such as Mzia and Pweza. Statoil has drilled ten exploration & appraisal wells in Block 2, and also found an enormous amount of gas at the structures such as Zafarani and Lavani. The amounts of discovery made by both companies are almost identical. The GIIP of BG Group and Statoil are 20-22Tcf and 21Tcf, respectively, though these are rough numbers at this moment. Contingent Resources of BG Group is reported at 16Tcf. Both companies have a plan to drill few wells in 2015 as second E&A campaign in order to work out an optimal field development plan. The campaign is expected to further increase GIIP and recoverable reserves.

According to Tanzanian Petroleum Development Company (TPDC), the estimated gas initial in-place at P10 at December 2015 was 47.13Tcf. This number has significantly increased from 37.5 Tcf at June 2013 with active exploration and delineation activities, and expected to grow further. The Natural Gas Utilization Master Plan (NGUMP) Draft-2 stipulates that the ultimate gas resources in the Tanzanian deepwater may far exceed 100Tcf. The present estimate may compare to that of an LNG giant Malaysia; 41.3 Tcf proven recoverable reserve at the end of 2015 according to the BP statistics. With these huge discoveries, it will be possible to implement gigantic gas projects; thus the government of Tanzania is drafting the NGUMP.

3.4.3 Development Plan

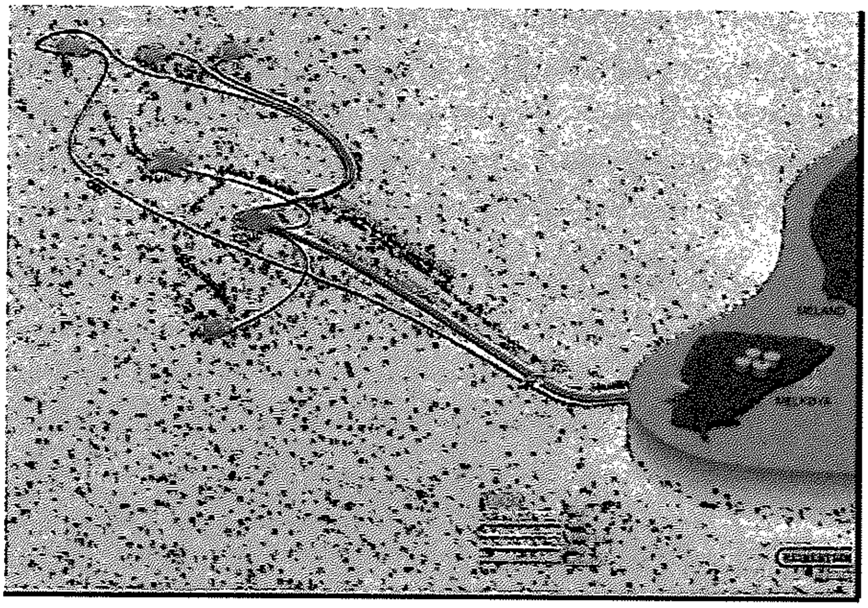
The biggest challenge facing BG Group and Statoil is now cost reduction in gas field development and LNG plant construction to cope with the sharp drop in oil and LNG prices observed since 2014. In particular, the global LNG supply/demand balance is anticipated to be looser as Japan is recovering from the Fukushima-Daiichi nuclear accident while additional LNG supply will emerge in North America based on shale gas. The oil companies are seriously studying innovative ideas which shall optimize the investment in all areas.

1) Selection of Subsea Production System

There are basically two deep-sea gas field production systems, namely, floater supported and no floater supported system. BG Group and Statoil are now studying which is the best system to be adopted technically and economically to develop deep-sea gas fields in Tanzania. In the former system, fluids produced from subsea wells are transferred via riser pipe to a floating processing platform, which is set on site. Then, fluids are dewatered, and condensate is extracted when necessary before being sent to LNG plant onshore. In the latter system, fluids produced from subsea wells are not treated, and they are transported directly to onshore LNG plant through a long distance pipeline.

Most deepwater gas fields adopt a floater supported system because a number of problems can occur when untreated well flow is transported over long distances at great depths. Among others, hydrate formation is the biggest one, which may plug the pipeline in the worst case. With regard to control of subsea wells, a floater supported system is more reliable because electricity and control signal are provided through umbilicals from a floating platform, while in the case of no floater system, they are provided through very long umbilicals from onshore.

In the meantime, a floater supported system has a drawback, namely, it is costly because of an expensive floating processing platform to be deployed. So, in order to make a no floater supported system a viable solution, long distance untreated well stream technology has been strenuously developed on the Norwegian continental shelf.



(Source) Courtesy of Statoil

Figure 3.4-2 Snøhvit Subsea Production System

In 1999, production from Midgard gas field came online through 54km long pipeline, which connects to a neighboring big gas field already developed. In 2007, Ormen Lange and Snøhvit started operation as the first major gas field development, where unprocessed gas stream was transported from subsea to shore directly. Ormen Lange, which lies 120 kilometers offshore at the water depth of 850–1100 meters, is the third largest gas-field in Europe and Norway's first deepwater project. Snøhvit, which lies 143km offshore at the water depth of 250–345 meters, set a record distance for pipeline transportation of untreated well-flow.

Snøhvit comprises Snøhvit itself and neighboring gas fields, i.e., Albatross and Askeladd. Combined gas in place of these fields is about 11 Tcf. At present, there are 9 production wells drilled (six wells in Snøhvit itself, and three wells in Albatross). Gas is fed into the LNG plant (4.2 million tpa) on Melkoya Island. Eleven wells are planned to be drilled in Askeladd in the future to compensate the production decline from Snøhvit.

As is shown in the above figure, gas streams from subsea well templates (D and E are located in Snøhvit, while N is located in Albatross) are gathered at PLEM (Pipeline End Manifold), and then transported to onshore facilities through 26 inch export pipe line. Electricity and control signal are provided to subsea well templates via CDU (Control Distribution Unit) through umbilicals. MEG (Mono Ethylene Glycol), which is gas hydrate inhibitor, is supplied to well templates via CDU.

Non-floater supported system is now becoming a promising solution to develop deep-sea gas field in other areas too. PEMEX, the Mexican state-owned petroleum company, is now developing Lakach gas filed, which is located 90 kilometers offshore in the Gulf of Mexico at the water depth of 850- 1,200 meters. Lakach is a small gas field, of which proven reserve is estimated at 850 billion cubic feet, and it is expected to start production in 2016.

Non-floater supported system could be a simple and cost effective solution in deep water Tanzania. However, it has a disadvantage in terms of recovery factor, the percentage of original gas volume in place that can be recovered. Field production rate as well as well flowing pressure will decline over the years because of decline in gas reservoir pressure. In order to maintain production and keep gas flowing to onshore facility, it is necessary to keep well flowing pressure at certain high level. In the case of floater supported system, gas compressor is set on the platform for this purpose. But, in case of non-floater supported system, gas compression is not possible because subsea gas compressor is not commercially available at present. As a result, the gas recovery factor will be reduced by a large margin. It is normally as high as 75 – 80%. However, it will be reduced to, for example, 65% in case of development with non-floater supported system.

Subsea gas compressor is now being deployed in Asgard gas field, which lies at the water depth of 250 -325 meters in offshore Norway. This technology is ready for commercial deployment in other areas around the world. However, it will take years before it is put into practice in the very deep field like offshore Tanzania.

As is explained above, both floater supported and non-floater supported system has pros and cons in terms capital cost, operation and recovery factor. It is essential to make a comprehensive analysis in order to select the most viable production system.

2) Pipe Laying

Pipe laying is another technical challenge in the deepwater gas field development in Tanzania. The seabed topography of Tanzania is characterized by a very narrow continental shelf. It is only 10 km wide in Block 2 area. The continental shelf is followed by a steep slope to the ocean floor, of which water depth is more than 2000 meters. Slope gradients are typically up to 10 degree although these are over 15 degree in places. There is a potential risk of mass slide of soft soils on the steep slope. There are also a series of active canyons running out perpendicular to the shorelines.

It is worthy to note that Ormen Lange has overcome technical challenges on pipe laying, such as rough sea floor with full of debris made from the Storegga Slides, and a steep slope up to 35 degree from 250 to 650 meter water depth. The Storegga Slides are the largest known landslides occurred at the edge of Norway's continental shelf between 8,400 and 2,200 years ago. Early planning and seafloor data gathering are keys to tackle technical challenges in Ormen Lange development. Useful lessons could be learnt from the Ormen Lange development even-though the conditions of Tanzanian and Norwegian deep-sea floor are not identical.

3) Gas Field Development Plan

At first, a candidate field or a combination of target fields should be identified to efficiently supply required amount of feed gas to the LNG plant for a long period. Then, production program should be established, which includes number of production wells and their locations. These works are conducted based on information about gas reservoir, which was obtained during the exploration and appraisal period. It is important to bear in mind that the amount of information is very limited, given the size of the field, or number of fields to develop. In addition to that, no dynamic data is available to predict field production performance except for a few data obtained through Drill Stem Test (DST). It is therefore very important to make a comprehensive analysis of reservoir performance, and make ready to revise the original plan when additional data is obtained through production well drilling.

As a matter of fact, significant dynamic reservoir data becomes available only after production has started. In the case of oil field development, early development, or, partial development is sometimes implemented, and it is possible to use the production data obtained in these stages to design an optimum full field development plan. On the other hand, in the case of gas field development for LNG project, gas production cannot commence until the LNG plant starts operation, which needs a big, predetermined amount of feed gas. This creates a wider degree of uncertainty for gas field development since the revision of initial development plan is virtually impossible. In this sense, it is to be noted that too much emphasis cannot be placed on the importance of reservoir engineering study.

Production well drilling cost accounts for large portion of initial field development capital cost. Therefore, it is important to improve production well drilling performance, so that drilling cost can be reduced correspondingly. This could be possible through comprehensive drilling engineering, which also help reduce troubles leading to longer drilling days than planned.